Methodology for Development of Carbon Sequestration Capacity Estimates

APPENDIX A

Prepared for

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Foreword

This document describes the methodologies that were used to produce the capacity estimates for the *2006 Carbon Sequestration Atlas for the United States and Canada*. The rationales presented were used to simplify assumptions for estimating the amount of carbon dioxide (CO_2) that can be stored in subsurface geologic environments of the onshore United States on a formation-by-formation or basin-by-basin basis.

The Regional Carbon Sequestration Partnerships (RCSPs) were charged with providing a quantitative assessment of the volume of CO_2 storage potential available in the subsurface environments of their Regions. These volumes are required to indicate the extent to which carbon capture and storage (CCS) technologies could contribute to the reduction of CO_2 emissions into the atmosphere. This assessment is a high-level overview and is not intended as a substitute for site-specific assessment and testing. The methodologies described in this document are designed to integrate results of data completed by the seven RCSPs for three types of geological formations: saline formations, unmineable coal seams, and hydrocarbon (oil and gas) formations. These methodologies were developed to be consistent across North America for a wide range of data. Results of this assessment are intended to be distributed by a geographic information system (GIS) and available as hard-copy results in the *2006 Carbon Sequestration Atlas for the United States and Canada*.

This document is a consensus product resulting from discussions among researchers representing all seven RCSPs. A subcommittee on Capacity Assessment convened by the Geologic Working Group of the RCSP in May of 2006 provided leadership for this effort. Methods used by the RCSP for estimating CO_2 storage capacity were inventoried, and methods in the literature were reviewed (Holloway and others, 1996; Brennan and Burruss, 2003; Carr and others, 2003; Bradshaw and others, 2006; Obdam, 2006). A workshop in Kansas July 11–12, 2006, provided a venue for broader discussion within the Geologic Working Group and GIS working groups, and additional discussion has occurred via phone conference and e-mail, leading to development of consensus on the approach presented here.

Contents

Introduction

Geologic carbon storage capacity is an estimate of the maximum amount of carbon dioxide (CO_2) that can be stored in geologic formations. The methodologies used to estimate geologic carbon storage capacities for this 2006 assessment consist of widely accepted assumptions about geologic storage mechanisms. Data collected by the Regional Carbon Sequestration Partnerships (RCSPs) during the first 3 years of the RCSP Initiative were used, along with these methodologies, to estimate geologic storage capacities. Diverse data from three types of geologic formations (saline formations, coal seams, and hydrocarbon formations) in the subsurface were summarized, interpolated, averaged, or generalized to calculate storage capacities on a subregional (formation or basin) scale by each of the seven RCSPs. Storage capacity methodologies for shale and basalt formations are currently under development.

Capacity estimates produced using these methodologies were unencumbered capacities, meaning that nongeologic factors that may limit the amount of CO_2 stored, such as cost of capture and transport or incompatible surface land uses.

Approach

The approach used to determine these methodologies was to (1) quantify at a subregional scale the storage resource (pore volume or adsorptive space) available (suitable saline, hydrocarbon, coal volumes) and (2) apply an estimate of the efficiency at which this resource can be used for storage of CO_2. Storage efficiency (E) represents a percentage of saline and coal resources that can be used for storage in all formations throughout the United States. Monte Carlo simulations, including ranges of uncertainty, were used to generate a low- and a high-efficiency estimate, which results in estimation of a low and a high value of capacity (Appendices 1 and 2). For hydrocarbon (oil or gas) formations, a single value of capacity was calculated because these storage volumes are well understood in comparison with other formation types. Any equivalent efficiency needed for each formation or group of formations was developed by each RCSP. Appendices 3 and 4 discuss standardization among types of data that were available for different regions.

Limits

The purpose of capacity estimates developed using these methodologies is to provide a high-level inventory of the capacity of the subsurface to store CO_2 in the United States and Canada. This information can be used by the general public, elected officials, and planners. These methodologies are not designed to support site-specific decisions, such as location of injection wells. Site-specific capacity per unit volume of the subsurface could be either higher or lower than the average per-unit volume storage in the Region assessed.

This assessment is not intended for highly quantitative cross-comparison of the capacity of each type of storage formation (for example, saline vs. oil and gas vs. coal) because in some cases the volumes are not separated (in some areas oil and gas formation and coal formation volume estimates are summarized collectively within saline formation storage estimates). In addition, the efficiencies assigned have not been normalized against each other to support a rigorous comparison. Cross-comparison of the capacity of each type of storage formation will become more quantitative as capacity is field-tested.

It is anticipated that capacity estimates will be updated as a result of acquiring new data, developing different methodologies and assumptions, and using comparatively more conservative standards or more aggressive standards. It is also expected that data quality and conceptual understanding of the carbon sequestration process will be improved over the next few years, which will refine capacity estimates.

Reporting

The RCSPs began by compiling data that was collected in their respective Regions and submitting it to the National Carbon Sequestration Database and Geographical Information System (NATCARB). Polygons enclosing each area assessed (formation or basin) with an attached database file (.dbf) were the preferred method of reporting. In the database, a low and a high estimate of saline formation and coal capacity in metric tons of CO_2 were recorded for each polygon, with a low value and a high value generated using the low and high values of storage efficiency (E) provided in this document. For storage in oil and gas formations, a capacity in metric tons of CO_2 was calculated for each formation, play, or region with individual or total oil and gas formation storage capacity displayed in a polygon. Data that support the calculated volumes (for example, thickness, depths, and porosity maps and grids, and any intermediate calculations such as per-unit or per-grid cell capacity) were archived by each RCSP.

Estimates of near-zero (0) capacity were acceptable for regions that have little chance of finding large-capacity storage using technologies now under consideration. An example of areas that have near-zero capacity are regions of exposed or shallow (<2,500 feet) plutonic or metamorphic basement rocks. In some assessments, these rock types do not provide adequate seals.

Placeholder values for capacity were accepted for areas that had not been assessed or which had been partly assessed but quantitative data were too incomplete to calculate a capacity (for example shale and basalt). Unassessed values were used to indicate that the area had not been studied and the presence of adequate saline, oil and gas, or unminable coal deposits was not yet available in the RCSP database. Unquantified values were used to indicate areas where assessment had been started and that data suggest that the area may have capacity; however, adequate or adequately quantitative data (for example, average porosity or thickness) were sparse or absent.

The Department of Energy (DOE) RCSP Program is intended to leverage local expertise on many aspects of carbon capture and sequestration technologies. If an alternative geographical information system (GIS) or mapping approach was required to show a Region's capacity, this approach was documented.

Types of Geologic Environments

For the purposes of this assessment, the subsurface was categorized into five major geologic formations: saline formations, coal seams, hydrocarbon (oil and gas) formations, shale, and basalt formations. Each of these is defined and input parameters for capacity calculations are described below. Storage capacity has been quantified where possible for saline, coal, oil, and gas, whereas shale and basalts are presented as future opportunities and presented as bulk resources.

Saline Formations

A saline formation assessed for storage is defined as a porous and permeable body of rock containing water with total dissolved solids (TDS) greater than 10,000 mg/L, which has the capacity to store large volumes of CO_2. Capacities were determined for all saline formations below 2,500 feet where adequate data was available. A saline formation can include more than one named geologic formation or be defined as only part of a formation. More than one saline formation can be assessed within a vertical sequence of rocks. Many formations are part of the total CO_2 volume that occupies structurally defined basins, and in this case, the name of the basin is commonly used to describe multiple formations. However, in some cases, the conceptualization and terminology were not appropriate, and in these cases the customary local terminology was accepted instead. Assumptions used in this assessment included (1) saline formations are heterogeneous and therefore under multiphase conditions; (2) only 20 to 80% of the area inventoried and 25 to 75% of the formation thickness assessed would be occupied by CO_2; and (3) the efficiency factor accounts for net to effective porosity, areal displacement efficiency, vertical displacement efficiency, gravity effects, and microscopic displacement efficiency.

Saline formations assessed for storage were restricted to those where the following basic criteria for the storage are met: (1) pressure and temperature conditions in the saline formation are adequate to keep the CO_2 in dense phase (liquid or supercritical), (2) a suitable seal is present to limit vertical flow of the CO_2 to the surface, and (3) salinity in the saline formation is such that injection is acceptable under provisions of the Underground Injection Control (UIC) Program. For this assessment, a depth of 2,500 feet below surface was accepted as a reasonable proxy for these criteria to be met. At a later time, new data or analysis may show sustainable storage at depths <2,500 feet.

For site-specific evaluations, exceptions may be required where local conditions indicate that a locality-specific modification is required. Examples of local conditions and locality-specific modification of this depth are

(1) abnormally deep water table (adjust depth cutoff to assure that CO_2 is dense in the saline formation, or assume that a gas phase cap is acceptable);
(2) abnormally high or low geothermal gradient (adjust depth cutoff to assure that CO_2 is dense in the saline formation);
(3) seal of sufficient quality and geometry to retain CO_2 in dense phase in the subsurface may not be present over the entire area (reduce area [A] and thickness [h] to the volume where seal is present);
(4) salinity is <10,000 mgL (reduce A and h to the volume where salinity is >10,000 mg/L, or, if not applicable for a region, assume that a waiver of relevant UIC rules will be granted).

In this assessment, details of the storage mechanism within a saline formation are not specified. No distinction is made between CO_2 that is stored as an immiscible phase within structural or stratigraphic geologic traps; CO_2 that is stored as an immiscible phase outside of traps (for example, trapped in pores by capillary processes); CO_2 that is stored as dissolved phase in saline; and CO_2 that is precipitated as minerals. However, displacement of saline in the pore volume by immiscible CO_2 is the fundamental mechanism implicit in the calculations. This issue is explained in more detail in Appendix 3, which provides a discussion of the equivalence of displacement-based capacity to dissolution- based capacity. Researchers within the RCSP recognize that capacity estimates will be refined as conceptualization of processes and quantification of subsurface data mature. A range of storage capacity was therefore calculated reflecting these uncertainties by proving the 15 and 85% confidence level from the Monte Carlo distribution used to calculate storage efficiency (Appendix 1).

The volumetric equation for capacity calculation in saline formations with consistent units assumed is as follows:

$$G_{CO2} = A\, h_g\, \phi_{tot}\, \rho\, E$$

Parameter	Units*	Description
G_{CO2}	M	Mass estimate of saline-formation CO_2 storage capacity
A	L^2	Geographical area that defines the basin or region being assessed for CO_2 storage-capacity calculation
h_g	L	Gross thickness of saline formations for which CO_2 storage is assessed within the basin or region defined by A
ϕ_{tot}	L^3/L^3	Average porosity of entire saline formation over thickness hg. Total porosity of saline formations within each geologic unit's gross thickness divided by hg
ρ	M/L^3	Density of CO_2 evaluated at pressure and temperature that represents storage conditions anticipated for a specific geologic unit averaged over hg
E	L^3/L^3	CO_2 Storage Efficiency Factor that reflects a fraction of the total pore volume that is filled by CO_2

* L is length; M is mass

Monte Carlo simulations estimated a range of E between 1 and 4 percent of the bulk volume of saline formations for a 15 to 85% confidence range (Appendix 1).

This assessment was conducted at a subregional (basin or regional) scale, and the details of calculation methodologies used were determined by each RCSP. A few examples include the following:

- Create two- or three-dimensional grids of capacity and sum them.
- Average parameters across the saline formation and multiply the average values using the volumetric equation.
- Assess capacity of one or more stratigraphically distinct named formations.
- Group permeable strata more coarsely in areas of greater complexity or less well-defined stratigraphy.

These methods are acceptable as long as they approximate algebraic equality. To approximate algebraic equality, input values must be applicable to the volumes assessed. For example, it is critical that ϕ_{tot} be an average that represents average porosity over the gross thickness hg. If thickness hg includes nonformation rocks, the porosity of these rocks should be represented by ϕ_{tot} in a proportion similar to that of their occurrence in the formation. Furthermore, ϕ_{tot} should not equal effective (or interconnected) porosity.

Oil and Gas Reservoirs

Oil or gas reservoir storage capacity for this assessment was defined as volumes of the subsurface that have hosted natural accumulations of oil and/or gas and that could, in the future, be used to store CO_2. Mapping of the seal to oil and gas reservoirs is not required because the entrapment of hydrocarbons is considered evidence that a CO_2 containment seal is present and the associated water is assumed to be nonpotable. Minimum depth was assigned by each RCSP. Production of hydrocarbons from these reservoirs has demonstrated that pores within the produced area are interconnected and can therefore be accessed by CO_2. In some cases, pressure is depleted significantly as a result of production, which can be conceptualized as volumes that can be replaced by repressurizing these reservoirs with CO_2.

Storage volume methodology for oil and gas reservoirs was simplified to provide a nationwide base-case. Calculation was based on quantifying the volume of hydrocarbons produced and assuming that they could be replaced by an equivalent volume of CO_2, where both hydrocarbon and CO_2 volumes were calculated at initial formation pressure or a pressure that was considered a maximum CO_2 storage pressure. Two main methods were used to estimate the CO_2 storage volume: (1) a volumetrics-based CO_2 storage estimate and (2) a production-based CO_2 storage estimate. The method selected by each RSCP was based on available data. Appendix 4 describes a case study suggesting that the two methods can be used as equivalents. The two methods have storage efficiency factors built into their respective methodologies. No range of capacity values is proposed for oil and gas reservoirs, reflecting a relatively good understanding of volumetrics of this system.

Volumetrics-based CO_2 Storage Estimate for Oil and Gas Reservoirs—The volumetrics-based CO_2 storage estimate uses standard industry methods to calculate original oil in place (OOIP) or original gas in place (OGIP). OOIP is calculated by multiplying reservoir area (A), net oil column height (h_n), average effective porosity (ϕ_e), and oil saturation (1 - water saturation as a fraction). A reservoir-specific fraction of OOIP is estimated to be accessible to CO_2; the fraction can include multiple mechanisms, such as dissolution of CO_2 in situ into oil and water. In the equation below, this fraction is defined as E and can be derived from local experience or reservoir simulation. For site-specific studies, reservoir volumetrics involving gas require consideration of pressure and reservoir drive mechanism. Because of previous extensive experience in estimating volumetrics of reservoirs, regional, play, or reservoir-specific values supplied by each Partnership were used.

The general form of the volumetric equation used is similar to that used from saline formations, except that E involves original oil or gas in place.

$$G_{CO2} = A\, h_n\, \phi_e\, (1\text{-}S_w) B_o\, \rho\, E$$

Parameter	Units*	Description
G_{CO2}	M	Mass estimate of hydrocarbon reservoir CO_2 storage capacity
A	L^2	Area that defines oil or gas reservoir that is assessed for CO_2 storage capacity calculation
h_g	L	Hydrocarbon column height in the reservoir
ϕ_e	L^3/L^3	Average porosity over net thickness h_n. Effective porosity of reservoir divided by h_n
S_w	L^3/L^3	Average water saturation within the total area (A) and net thickness (h_n)
B	L^3/L^3	Reservoir volume factor; converts standard oil or gas volume to subsurface volume (at reservoir pressure and temperature)
ρ	M/ L^3	Density of CO_2 evaluated at pressure and temperature that represents storage conditions in the reservoir averaged over hn
E	L^3/L^3	CO_2 storage efficiency factor that reflects a fraction of the total pore volume from which oil and/or gas has been produced and that can be filled by CO_2

* L is length; M is mass

It is acceptable to distribute these parameters over a geocellular grid and sum the values obtained for each cell or to multiply values averaged over the formation (GIS polygon), as long as the resulting values are approximately equivalent.

Production-based CO_2 storage estimate for oil and gas reservoirs—A production-based CO_2 storage estimate is possible if acceptable records are available on volumes of hydrocarbons produced. Produced water was not considered in the estimates, nor was injected water (waterflooding), although these volumes may be useful in site-specific calculations. It is necessary to apply an appropriate reservoir volume factor (B) to convert surface hydrocarbon volumes reported as production to subsurface volumes, including correction of solution gas volumes if gas production in an oil reservoir is included. No area, column height, porosity, residual water saturation, or estimation of the fraction of OOIP that is accessible to CO_2 was required because production reflected these reservoir characteristics. If data were available, it was possible to apply efficiency to production data to convert it to CO_2 storage volumes; otherwise replacement of produced hydrocarbons by CO_2 on a volume-for-volume basis (at reservoir pressure and temperature) was accepted.

Simplifying assumptions for oil and gas reservoirs—No effort was made to consider the economic aspects of oil and gas reservoirs. No distinction was made between reservoirs that were in production and those that were or would soon become depleted or abandoned. RCSP researchers are aware that sophisticated analysis of the potential for use of oil and gas reservoirs for CO_2 sequestration can be made, including use of CO_2 for enhanced oil recovery (EOR) and enhanced gas recovery (EGR). A large number of variables could be considered that potentially increase or decrease the estimate of CO_2 storage available in the reservoir. However, it was not feasible to standardize these variables on a homogeneous nationwide approach, but it will be of value in more focused assessments. Moreover, Appendix 4 shows a study of production and volumetric data for the Illinois Basin illustrating a simulation-based storage efficiency (that accounts for most all of these variables), with volumetrics compared very similarly to the production replacement method.

Examples of factors not explicitly considered in the production-based method that might increase the volume that could be stored include miscibility of CO_2 into oil, dissolution of CO_2 into residual and associated water, mineral trapping, and pressure decline as a result of production. Optimizing reservoir engineering via integration of reservoir characterization with well placement, completion, conformance control, and injection strategies may increase storage capacity. Parameters not considered that may limit the volume that can be stored include imperfect inversion of processes that occurred during production—for example, replacement of produced oil or gas by water (CO_2 may not completely replace this imbibed water), production of gas by solution gas drive, and waterflooding. In addition, it may not be realistic to assume that the volume of CO_2 stored is equivalent to the volume of oil and gas originally trapped because of pressure perturbations of the formation during production (for example, compromise to the seal by well penetration or by deformation during production) or that seal will respond identically to trapping CO_2 as the original fluid stored.

Coal Beds

The adsorptive nature of coal (quantified as sorptive capacity, expressed in standard cubic feet gas per unit volume or mass of coal) compared with that of porous media was expected to cause the range of parameters for displacement efficiency terms to be much higher than for porous media. Gas concentration from the Langmuir isotherm was substituted for the porosity that was used in other capacity calculations. We assume that delineation of most coals via mapping is better than quantification of porosity distribution in saline formations; however, some unmapped heterogeneity at a basin scale was included within the estimated value of E. The definition of unminable coal varies from region to region due to depth distribution of the total resource relative to the rate and cost of mining.

Gas concentration is ideally determined from Langmuir adsorption isotherm data. These gas contents represent the maximum gas content adsorbed in the coals. Alternatives to using adsorption data would be using desorption data, which, in areas of underpressurized coals, will have gas-content values less than those of the Langmuir isotherm data. Desorption data can be used as a substitute for Langmuir adsorption isotherm data, recognizing that the gas-content values will be underreported, and, hence, sequestration capacity of the coals will be lower when compared with using Langmuir (saturated) values.

The volumetric equation with consistent units assumed is

$$G_{CO2} = A\ h\ C\ \rho\ E$$

Parameter	Units*	Description
G_{CO2}	M	Mass estimate of CO_2 storage capacity of one or more coal beds
A	L^2	Geographical area that outlines the coal basin or region for CO_2 storage capacity calculation
h_g	L	Gross thickness of coal seam(s) for which CO_2 storage is assessed within the basin or region defined by A
C	L^3/ L^3	Concentration of CO_2 standard volume per unit of coal volume (Langmuir or alternative); assumes 100% CO_2 saturated coal conditions; if on dry-ash-free (daf) basis, A and h must be corrected for daf
ρ	M/ L^3	Standard density of CO_2
E	L^3/L^3	CO_2 Storage Efficiency Factor that reflects a fraction of the total coal bulk volume that is contacted by CO_2

* L is length; M is mass

The CO_2 storage efficiency factor has several components that reflect different physical barriers that inhibit CO_2 from contacting 100% of the coal bulk volume of a given basin or region. Depending on the definitions of area, thickness, and CO_2 concentration (from Langmuir), the CO_2 storage efficiency factor may also reflect the volumetric difference between bulk volume and coal volume. For example if A and h are based on dry-ash-free (daf) conditions, C must have a daf basis too. Additionally, because gross thickness is used in the equation above, E includes a term that adjusts gross thickness to net thickness. Appendix 2 provides the assumptions used to estimate E for coal. Monte Carlo simulations estimated a range of E between 28 and 40%; these values provide a 15 to 85% confidence range. Details are provided in Appendix 2.

Data Density and Uncertainty

The RCSPs worked toward assigning levels of confidence to storage estimates of specific sink types. Available data such as well penetration and seismic surveys are unevenly distributed, and the level of characterization of the subsurface both by the geoscience community and by the RCSP program is variable. In addition, the complexity of the subsurface is variable; in some areas reasonably confident extrapolations can be made between data points; in others, confidence in correlation between data points drops sharply with distance. As an example, a simple rubric is provided below for each Partnership to provide a 1 (low) to 9 (high) relative index of availability of data needed to estimate capacity and level of confidence in the assessment on a basin or formation scale.

Confidence Indicator

Subsurface Heterogeneity			
Complex subsurface, numerous structures at spacings of <2 miles, highly discontinuous formation properties at <2 mile spacing, typical of tectonically deformed areas	5	3	1
Moderately hetero-geneous subsurface, structure and anisotopy present but repetitive at 2-10 mile spacing possible to interpolate rock properties for up to 10 miles	7	5	3
Structural complications are infrequent and range of rock properties can be projected over areas >10 miles.	9	7	5
	Well density avg. > 1 well/square mile seismic survey spacing average >1 line per 10 linear mile	Well density avg. > 1 well/9 square mile seismic survey spacing average >1 line per 50 linear mile	Well density avg. > 1 well/100 square mile seismic line spacing average >1 line per 100 linear mile

Data Density

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Appendices

Appendix 1. Estimation of the Storage Efficiency Factor for Saline Formations

Efficiency is the multiplicative combination of volumetric parameters that reflect the portion of a basin's or region's total pore volume that CO_2 is expected to actually contact. The CO_2 storage efficiency factor for saline formations has several components that reflect different physical barriers that inhibit CO_2 from contacting 100 percent of the pore volume of a give basin or region. Depending on the definitions of area, thickness, and porosity, the CO_2 storage efficiency factor may also reflect the volumetric difference between bulk volume, total pore volume, and effective pore volume.

Because formation thickness and total porosity are used in the saline capacity equation, efficiency must include terms that adjust gross thickness to net thickness and total porosity to effective porosity (interconnected).

The terms can be grouped into a single term that defines the entire basin's/region's pore volume and terms that reflect local formation effects in the injection area of a specific injection well. Assuming that CO_2 injection wells can be placed regularly throughout the basin/region to maximize storage, this group of terms is applied to the entire basin/region. Given this assumption, the capacity estimate is the maximum storage available because there is no restriction on the number of wells that could be used for the entire basin/region area. Because formation heterogeneity terms are included, this estimate could be considered a "reasonable" maximum storage estimate.

Terms included in the CO_2 storage efficiency factor are:

Term	Symbol (range)	Description
Terms used to Define the Entire Basin/Region Pore Volume		
Net to total area	A_n/A_t (0.2–0.8)	Fraction of total basin/region area that has a suitable formation present.
Net to gross thickness	h_n/h_g (0.25–0.75)	Fraction of total geologic unit that meets minimum porosity and permeability requirements for injection.
Effective to total porosity ratio	ϕ_e/ϕ_{tot} (0.6–0.95)	Fraction of total porosity that is effective, i.e. interconnected
Terms used to Define the Pore Volume Immediately Surrounding a Single Well CO_2 Injector		
Areal displacement efficiency	E_A (0.5–0.8)	Fraction of immediate area surrounding an injection well that can be contacted by CO_2; most likely influenced by areal geologic heterogeneity such as faults or permeability anisotropy.
Vertical displacement efficiency	E_I (0.6–0.9)	Fraction of vertical cross section (thickness), with the volume defined by the area (A) that can be contacted by the CO_2 plume from a single well; most likely influenced by variations in porosity and permeability between sublayers in the same geologic unit. If one zone has higher permeability compared with others, the CO_2 will fill this one quickly and leave the other zones with less CO_2 or no CO_2 in them.
Gravity	E_g (0.2–0.6)	Fraction of net thickness that is contacted by CO_2 as a consequence of the density difference between CO_2 and in situ water. In other words, 1-Eg is that portion of the net thickness **not** contacted by CO_2 because the CO_2 rises within the geologic unit.
Microscopic displacement efficiency	E_d (0.5–0.8)	Portion of the CO_2-contacted, water-filled pore volume that can be replaced by CO_2. Ed is directly related to irreducible water saturation in the presence of CO_2.

The range of values for each parameter is an approximation to reflect various lithologies and geologic depositional systems that occur throughout the Nation. The maximum and minimum are meant to be reasonable high and low values for each parameter.

The table below gives results of six Monte Carlo simulations of the distribution of values described. (The 4th and 5th cases were run to assess sensitivity to the input parameters and were not considered valid for interpretation of E.) Selection of distributions was to see the effect of choice of distribution on the final answer. The P_{50} case seems less sensitive to choice of distribution. P_{15} and P_{85} cases are more sensitive to the distribution selection and parameters that describe the distribution. No rigor was given to selection of the distribution or the parameters that describe them. The intent of these Monte Carlo simulations was to give some basis or perspective for choice of the magnitude of total storage efficiency (E). In other words, this is an example of a combination of ranges of parameters and distributions that would yield a P_{50} E of approximately 1.8 to 2.2%.

Case	Parameter	Range	Distribution	P_{15}	P_{50}	P_{85}	Comment
Base-uniform	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5-0.8	Uniform Uniform Uniform Uniform Uniform Uniform Uniform	1.6	2.7	4.2	
Base-normal with variance 1.0 max-min difference	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Normal Normal Normal Normal Normal Normal Normal	0.44	1.8	4.1	Median given as midpoint of range; variance given as max less median (broad flat normal distribution)
Base-normal with variance 2.0 max-min difference	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Normal Normal Normal Normal Normal Normal Normal	0.22	1.9	10	Median given as midpoint of range; variance given as twice max less median (very broad, flat normal distribution) P_{85} likely too high as wide distribution makes values of some components over 1.0
Base-normal with variance ½ max-min difference	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Normal Normal Normal Normal Normal Normal Normal	1.2	2.2	3.7	Median given as midpoint of range; variance given as one-half max less median (narrow, spike normal distribution)
Base-normal with variance 1.0 max-min difference with minimum imposed	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Normal Normal Normal Normal Normal Normal Normal	1.7	3.7	8.0	Median given as midpoint of range; variance given as max less median (broad flat normal distribution); minimum equals low of range
Base-mixed distribution	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Uniform Normal Uniform Normal Log Normal Normal Normal	0.65	1.9	4.4	Change in distribution based on possible petrophysical distribution

Averaging and rounding these values results in a **low value of E of 0.01 and a high value of 0.04**; these values provide a 15 to 85% confidence range.

Appendix 2. Estimation of Storage Efficiency Factor for Unminable Coal Seams

Efficiency is the multiplicative combination of volumetric parameters that reflect the portion of a basin's or region's coal bulk volume that CO_2 is expected to actually contact.

The terms that describe this volume can be grouped into one term that defines the entire basin's/region's coal bulk volume and the local formation effects in the injection area of a specific injection well. Assuming that CO_2 injection wells can be placed regularly throughout the basin/region to maximize the basin's coal storage, this group of terms is applied to the entire basin/region. The capacity estimate is therefore the maximum storage available because there is no restriction in the number of wells that could be used for the entire basin/region area. Because formation heterogeneity terms are included, however, this estimate could be considered a "reasonable" maximum storage estimate.

All of the terms are the same conceptually as with saline, except that the *effective porosity to total porosity* term was dropped. It is not in the coal volumetric equation; it is replaced by *concentration* from the Langmuir isotherm. Definitions in the table on the next page were modified for coal. Because of the lack of extensive enhanced coalbed methane (ECBM) field experience, ranges were based loosely on coalbed methane (CBM) production and computer modeling observations.

The adsorptiveness of coal compared to storage in porous media causes the range of parameters for displacement efficiency terms to be much higher than similar terms for porous media. Although geologic heterogeneity is expected in coals, the permeability reduction expected in coal due to CO_2 swelling will most likely have a "correcting" mechanism, which reduces the velocity of CO_2 as the coal swells and redirects CO_2 to lesser-swept parts of the coal seam. Because coals are thinner than saline formations, gravity effects will likely be very slight, so this term was raised also. The bulk coal terms (A/A and h/h) were increased because most basin coals would be better defined compared with saline formations.

Terms included in the CO_2 storage efficiency factor for coal are:

Term	Symbol (range)	Description
Terms used to Define the Entire Basin/Region Bulk Coal Volume		
Net to total area	A_n/A_t (0.6–0.8)	Fraction of total basin/region area that has bulk coal present; used if known or suspected locations are within a basin/region outline where a coal seam may be discontinuous. For example, in the Illinois Basin there are subregions within the basin where sand channels have incised and replaced coal. This situation can be handled through this term.
Net to gross thickness	h_n/h_g (0.75–0.90)	Fraction of total coal seam thickness that has adsorptive capability.
Terms used to Define the Coal Volume Immediately Surrounding a Single Well CO_2 Injector		
Areal displacement efficiency	E_A (0.7–0.95)	Fraction of the immediate area surrounding an injection well that can be contacted by CO_2; most likely influenced by areal geologic heterogeneity such as faults or permeability anisotropy.
Vertical displacement efficiency	E_I (0.8–0.95)	Fraction of the vertical cross section (thickness), with the volume defined by the area (A) that can be contacted by a single well; most likely influenced by variations in the cleat system within the coal. If one zone has higher permeability than others, the CO_2 will fill this one quickly and leave the other zones with less CO_2 or no CO_2 in them.
Gravity	E_g (0.9–1.0)	Fraction of the net thickness that is contacted by CO_2 as a consequence of the density difference between CO_2 and the in-situ water in the cleats. In other words, 1-E_g is the portion of the net thickness not contacted by CO_2 because the CO_2 rises within the coal seam.
Microscopic displacement efficiency	E_d (0.75–0.95)	Reflects the degree of saturation achievable for in situ coal compared with the theoretical maximum predicted by the CO_2 Langmuir Isotherm.

The range of values for each parameter is an approximation to reflect various coals. The maximum and minimum are meant to be reasonable high and low values for each parameter.

The following table gives results of five Monte Carlo simulations of the distribution of points that are given in the previous table. The selection of distributions was to see the effect of choice of distribution on the final answer. The P_{50} case seems less sensitive to choice of distribution. P_{15} and P_{85} cases are more sensitive to distribution selection and parameters that describe the distribution. No rigor was given to the selection of the distribution or the parameters that describe them. The intent of these Monte Carlo simulations was to give some basis or perspective for the choice of magnitude of total efficiency (E). In other words, this is an example of a combination of ranges of parameters and distributions that would yield a P_{50} E of 33%.

Case	Parameter	Range	Distribution	P_{15}	P_{50}	P_{85}	Comment
Base-uniform	A_n/A_t h_n/h_g E_A E_I E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Uniform Uniform Uniform Uniform Uniform Uniform	28	33	40	
Base-normal with variance 1.0 max-min difference	A_n/A_t h_n/h_g E_A E_I E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Normal Normal Normal Normal Normal Normal	25	33	43	Median given as midpoint of range; variance given as max less median (broad flat normal distribution)
Base-normal with variance ½ max-min difference	A_n/A_t h_n/h_g E_A E_I E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Normal Normal Normal Normal Normal Normal	29	33	38	Median given as midpoint of range; variance given as one-half max less median (narrow, spike normal distribution)
Base-normal with variance 2.0 max-min difference	A_n/A_t h_n/h_g E_A E_I E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Normal Normal Normal Normal Normal Normal	16	29	53	Median given as midpoint of range; variance given as twice max less median (very broad, flat normal distribution) P85 likely too high as wide distribution makes values of some components over 1.0
Base-normal with variance 1.0 max-min difference with minimum imposed	A_n/A_t h_n/h_g E_A E_I E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Normal Normal Normal Normal Normal Normal	32	39	49	Median given as midpoint of range; variance given as max less median (broad flat normal distribution); minimum equals low of range

Depending on how mapping was conducted, the value for E could reflect the volumetric difference between bulk volume and coal volume, or it could reflect coal-quality factors such as ash content, amount of moisture, heating value, vitrinite reflectance, maceral composition, and total organic content.

Compared with that of coalbed methane recovery the value of storage efficiency of 33% is relatively low. The difference is that 50 to 75% storage efficiency may be more likely in a well field where coal is present in 100% of the area studied. When applying this efficiency to a basin, two factors (A/A and h/h) reduce this value to account for the volumes of the basin that actually have coal present with adsorptive coal capacity. If these terms were removed or if we knew the volume of coal with 100% certainty, a storage factor of 57% would be predicted with this range of values. This storage factor is in agreement with coalbed methane recovery.

For the National Capacity Estimate, Monte Carlo simulations estimate a range of E of 0.28 to 0.40; these values provide a 15 to 85% confidence range.

Appendix 3. Comparison of Pore Volume Occupied by CO_2 Dissolution in Saline and Free Phase CO_2

Because some RCSPs used dissolution of CO_2 in water and other RCSPs used free-phase CO_2 to estimate their respective basins/regions' storage capacity, the total storage efficiency (E) derived for use in one technique is not equivalent or applicable to the other.

The dominant mechanism of CO_2 storage may change from storage of an immiscible free-phase to CO_2 dissolved in water over time, and the proportion of dissolved CO_2 to a basin's/region's pore volume would be larger than the proportion contacted by free phase CO_2. Several RCSPs focused on dissolved storage for capacity calculation. To avoid any RCSP's repeating a rigorous calculation of capacity with new methodology, a method of converting E for free-phase CO_2 to the equivalent E for dissolved CO_2 is desirable. The example below shows how it can be done.

Example calculation for a formation at 8,000 feet, with temperature of 140 °F and 3,500 pounds per square inch absolute (psia) saturated with 100,000 parts per million (ppm) water. The density of CO_2 is 48.55 pound mass per cubic foot (lbm/ft^3), and dissolution in this saline is 118 standard cubic feet/stock tank barrel (scf/stb). (MIDCARB, 2004, Midcontinent Interactive Digital Carbon Atlas and Relational database (MIDCARB), http://www.midcarb.org/calculators.shtml accessed February 14, 2007; Practical Aspects of CO_2 Flooding, 2002, Perry M. Jarrell, Charles E. Fox, Michael H. Stein and Steve L. Webb Society of Petroleum Engineers (SPE) Monograph 22, 220p.)

Using a common basis of 1 ft^3 of pore volume, the 48.55 lbm of free-phase CO_2 occupies 1 ft^3 of pore space.

$$\left(\frac{118\,\text{scf} - CO_2}{\text{stb} - \text{water}}\right)\left(\frac{1\,\text{bbl}}{5.615\,\text{ft}^3}\right)\left(\frac{1\,\text{ton} - CO_2}{17{,}140\,\text{scf} - CO_2}\right)\left(\frac{2000\,\text{lbm}}{\text{ton}}\right) = \frac{2.452\ \text{lbm - }CO_2}{\text{ft}^3\text{ - pore volume}}$$

For dissolution of CO_2 into water, 1 ft$_3$ of pore space is occupied by water; 118 scf of CO_2 100% saturates a stb of 100,000 ppm water at 140 °F and 3500 psia. Converting to lbm/ft^3

There is a slight difference, usually less than 1%, between a stock tank barrel of water and a formation barrel of water; for this example it was assumed that they were equal. Any increase or decrease in the 1 ft^3 of water volume due to dissolution of CO_2 was not included in this example.

The ratio of 48.55 to 2.452 is used to convert from the E derived for free phase to the E for dissolution, which is 19.8 in this example. If the E for free-phase CO_2 is 2%, the equivalent E for dissolution is 2 × 19.8, or 39.6%. Interestingly if the E-free phase was 5%, the equivalent E-dissolution for this example, is 99%. So at the assumed salinity, if 5% of a basin's pore volume is free-phase CO_2, the equivalent mass distributed via dissolution in water would require 99% of the basin's pore volume.

Because of variation of pressure, temperature, and salinity as a function of depth across a basin or region, an average value should be used to calculate the conversion factor from free phase to dissolution for the entire region; otherwise a rigorous GIS study would be required to make the conversion at different values of pressure, salinity, and temperature.

Appendix 4. Comparison of CO_2 Storage Estimates in Oil Formations Using Production and Volumetrics

Background

The methodology chosen to assess CO_2 storage in oil formations depends primarily on available data. Two distinct data types are production and formation geometry. Production data include cumulative oil and (hydrocarbon) gas. For this analysis, cumulative gas production was considered for gas formations, except for associated gas of oil formations. Water production and water injection are not considered in this assessment; however, they might be considered in the future. Formation geometry data would need to include area, thickness, porosity, water saturation, and formation volume factors.

Production-Based CO_2 Storage Estimate

A simple method proposed in this assessment is to replace cumulative hydrocarbon production with an equivalent formation volume of CO_2. Doing so would require the hydrocarbon formation volume factor to convert the surface volume of hydrocarbon to formation pressure and temperature and CO_2 density to find the mass of CO_2 that would occupy the pore space previously occupied by oil or gas.

An advantage of using hydrocarbon production to estimate CO_2 storage is that production reflects a hydrocarbon (production) recovery factor, which is a portion of the original oil volume that was produced. (This recovery factor, much like the storage efficiency factor, would include formation heterogeneity influences on cumulative oil production). Disadvantages of using hydrocarbon production to estimate CO_2 storage include incomplete data records and various stages of oil-field maturity (percent depleted).

Replacement of produced fluids with CO_2 requires close examination to understand the inherent assumptions required to assess CO_2 storage using cumulative fluid production. When oil is produced from a formation during primary production, either associated hydrocarbon gas or water replaces the oil within the pore space. If the formation was waterflooded, a portion or all of the free gas is removed and additional oil is produced; both are replaced by water. In any case, using an oil-production-based estimate for CO_2 storage, it is necessary to assume that the fluids that replaced the oil can be replaced with CO_2. Also, using cumulative oil production alone does not include the volume of CO_2 that would replace oil produced as a consequence of CO_2 EOR or dissolution of CO_2 into in situ oil and water.

Use of production (and injection) data to estimate CO_2 storage capacity requires assumptions of natural formation drive mechanisms, production history, and CO_2 replacement ratio. For example, if the natural drive mechanism were solution gas drive and a large portion of free gas were liberated in situ and subsequently produced, use of oil and gas production to determine CO_2 storage would be appropriate. However, if the natural drive mechanism had been water encroachment via an underlying saline formation, oil may have been replaced with an equivalent volume of water. Stored CO_2 would have to force water out of the pore space similar to storage in a saline formation, and replacement of oil production with CO_2 may be overly optimistic.

Use of water and gas production and injection may be done on a field by field basis if data are available; however, this level of assessment is not expected for this analysis. Cumulative water production and injection are likely very large and similar in magnitude for mature oil formations; the difference would not afford much storage. Additionally, much of the mobile water can most likely be displaced during the CO_2 injection process. If a large portion of cumulative gas production were from an original gas cap, use of gas production to estimate CO_2 storage would likely be a good approximation; however, if a large portion of the gas production were from solution gas, the use of gas production would overestimate CO_2 storage in an oil formation.

Volumetrics-Based CO_2 Storage Estimate

Use of volumetrics to estimate CO_2 storage is based on an estimate of original oil in place (OOIP). A fraction of the OOIP is assumed to be replaced by CO_2 (storage efficiency factor). This fraction could be derived from historical observations of the West Texas CO_2 experience or compositional simulation of the CO_2-EOR process for general geologic models of a basin. Because these approaches are based on the CO_2 injection process, all of the storage mechanisms (free phase CO_2, dissolved CO_2 in water and oil) modeled and production variations associated with primary production and waterflooding are included in the storage efficiency factor.

Comparison

As a result of the data available within each region, some RCSPs used production and some used volumetrics. To develop a National storage estimates using comparative methodology, an adjustment to one method's results would be needed to have a consistent capacity estimate between regions. Data sets that had both types of data for the same fields were thus required. Two data sets were available to compare the CO_2 storage estimates using oil production and volumetrics. For the Illinois Basin, a data set of cumulative oil production by field and formation geometry data by formation was available for comparison.

A second data set based on compositional simulation results using Landmark's VIP software was also available. In Phase I the Midwest Geologic Sequestration Consortium (MGSC) modeled three geologic units in nine different oil fields in the Illinois Basin. The geologic units were selected from the most prolific in the Basin. Only very qualitative history matching was done because the main goal was to have geologic models that represented the Basin's oil formations. Moreover, ultimate oil recovery was the goal, not specific, historical, field performance. Each formation was simulated under miscible and immiscible conditions. Consequently, this data set provided 18 model results to compare each method with the actual CO_2 storage estimated in the model. All models had 25 years of solution gas drive, followed by 40 years of waterflooding, followed by 20 years of CO_2 EOR. WAG or continuous CO_2 injection; however, the continuous data set was only used for comparison because it was expected to be a more likely scenario in a predominantly sequestration (vs. a predominantly EOR) environment.

Compositional Modeling Data Set

For each geologic formation, a range of CO_2 storage factors for miscible and immiscible conditions were derived from the compositional simulation results. The average of this storage factor range was applied to the OOIP of each model to estimate the CO_2 stored. (Note that if the exact storage factor derived from each model had been applied to that specific model, the exact CO_2 storage volume would have been found.) Production-based CO_2 storage used oil production only. Actual storage is calculated from the model's gas injection and production.

The estimate of CO_2 storage using production data is slightly higher than the actual storage, and the CO_2 storage estimate using volumetrics is slightly lower than the actual storage (Figure 1). The 1:1 line would be a perfect prediction.

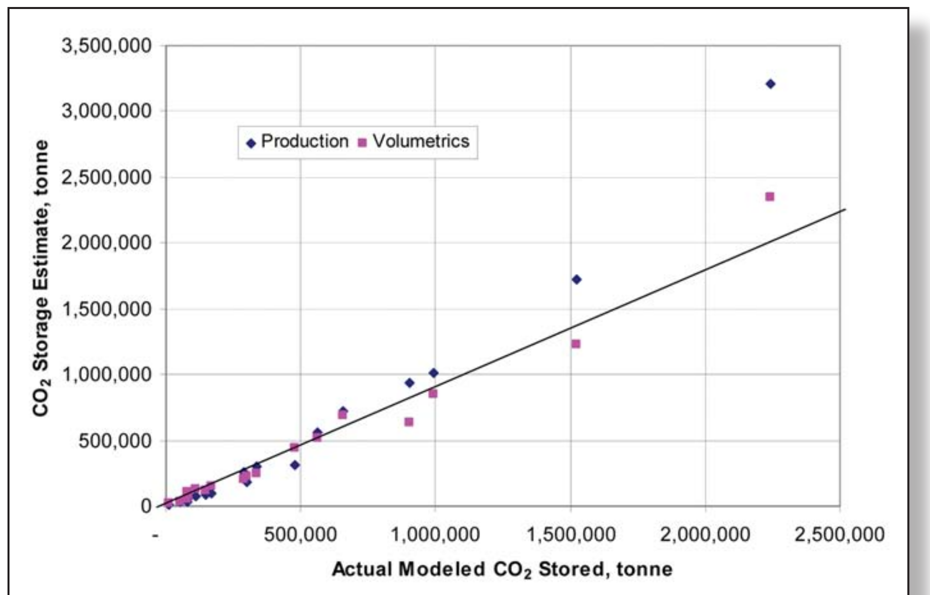

Figure 1. Comparison between CO_2 storage estimates on the basis of cumulative oil production (primary and waterflooding) and volumetrics using a storage factor derived from compositional simulation with the actual mass of CO_2 stored using the models.

When oil production is used, the trend is very similar to that of actual storage of up to 1 million tonne of CO_2 and then the general trend starts to deviate upward somewhat substantially, but only with two points. The volumetrics-based estimate is very similar to the actual storage of up to 0.6 million tonne of CO_2; however, the overall trend follows the 1:1 slope. Trendlines through the data (not shown) show that the volumetrics-based method is closer to fitting the 1:1 curve (slope of 0.96) and a y-intercept of zero (31 ktonne), as compared with the trendline through the production-based estimate (slope of 1.3 and y-intercept of 134 ktonne).

Figure 2 is a direct comparison of volumetrics- and production-based storage estimates. The production-based estimate overpredicts, as compared with the volumetrics-based method

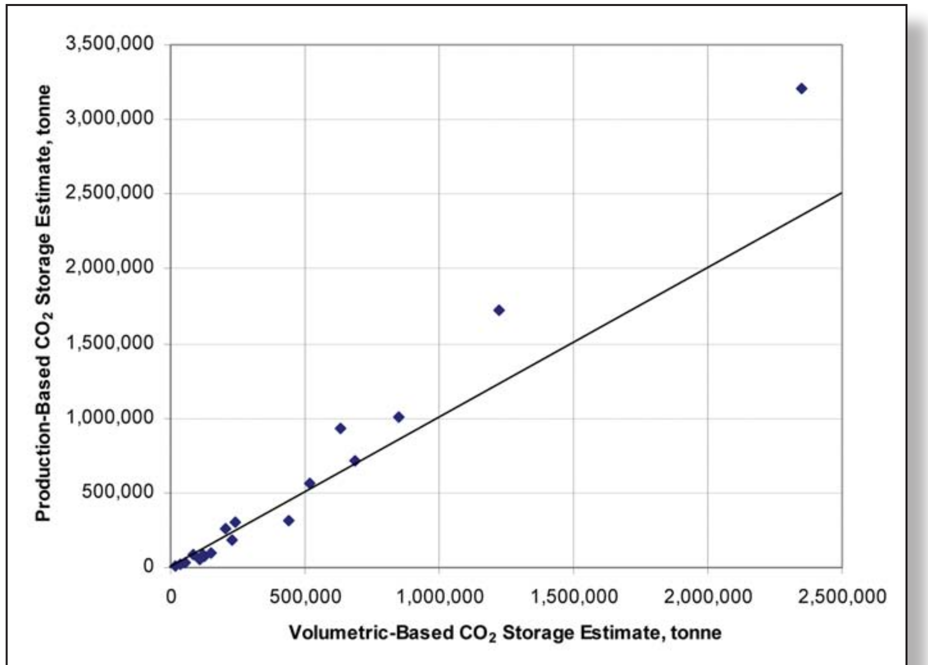

Figure 2. A direct comparison between volumetrics- and production-based CO_2 storage shows the slight overprediction of the production method compared with the 1:1 line shown.

Whereas the trend indicates that at higher storage values, the production-based method may overpredict storage, the simulation data set suggests that replacing cumulative oil production with an equivalent volume of CO_2 is an acceptable substitute for simulation-based storage factors.

Illinois Basin Oil-Field Data Set

Cumulative oil production is available by field for many oil fields in the Illinois Basin. Exceptions are several of the Kentucky oil fields, where no oil production was available. For fields that were drilled pre-law (1939), the Basin's oil-production records are questionable. Oil fields with very low (<1,000 bbl) reported production were removed. Additionally, shallower oil fields are the earliest discovered and are generally expected to have poorer production records.

Figure 3 is a comparison between production- and volumetrics-based CO_2 storage estimates. The trendline through the data has a slope of 1.08 and a y-intercept of 22 ktonne, which indicates very good comparison between the methods. To improve visualization of the data, Figure 4 is the same data on a log-log scale.

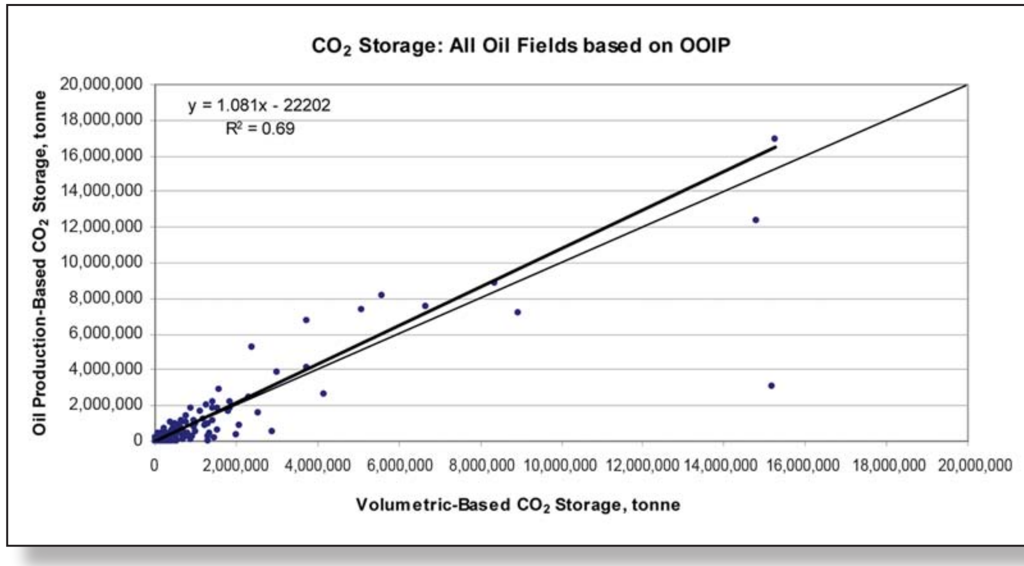

Figure 3. Cartesian plot of Illinois Basin oil fields with reported cumulative oil production exceeding 1,000 bbl. The trendline shows that each method gives comparable results.

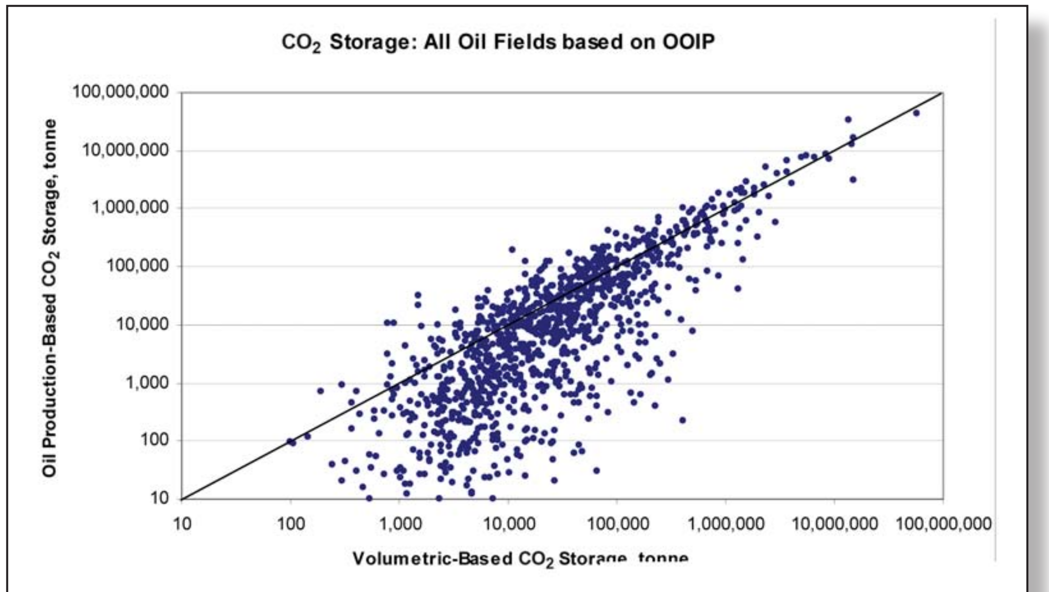

Figure 4. Log-log plot of Figure 3. Lower reported oil production yields lower calculated CO_2 storage using the cumulative oil-production method. The volumetrics method is independent of reported oil production and shows relatively higher CO_2 storage for oil fields with reported low oil production.

The log-log plot shows that relatively smaller oil fields tend to have lesser oil production reported—note the trend of the data to scatter more in the lower left of Figure 4.

To further understand the scatter in the data, the data were separated by cumulative oil, OOIP, and miscibility type. Classifying the Illinois Basin oil fields by cumulative production shows that those oil fields with relatively higher reported production have a more similar trend between the two methods (Figure 5). A trendline through each data grouping has a slope of about 0.85, which can be interpreted that the oil-production-based method is underpredicting by 15%. (The y-intercepts were relatively close to zero considering the maximum x and y-axes values.)

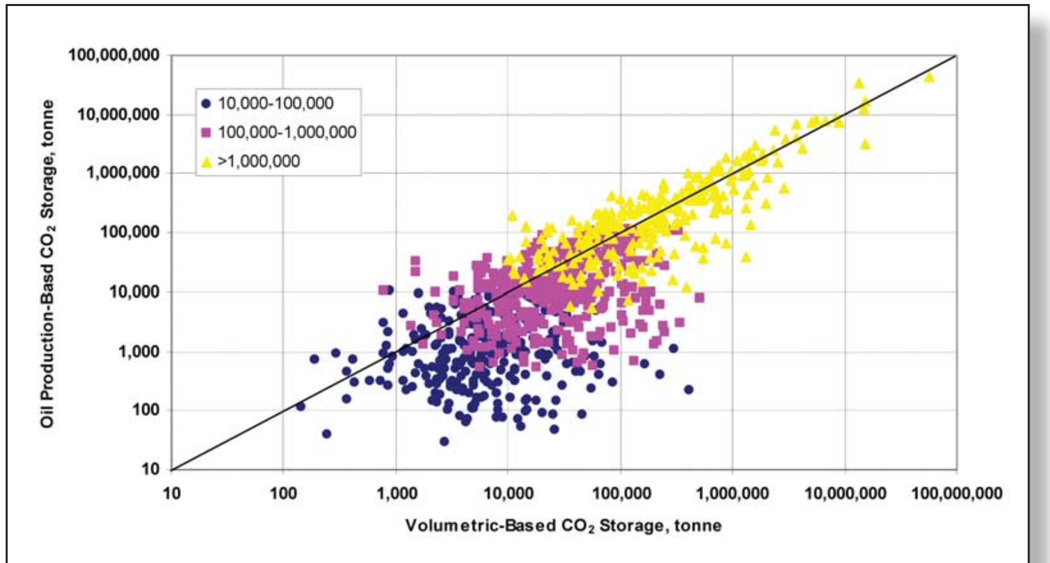

Figure 5. Oil fields in the basin are identified by three ranges of cumulative oil. Oil fields with larger reported oil production give relatively results similar to those between production- and volumetric-based methods.

To see the effects of OOIP on calculated storage estimates, fields were classified on the basis of ranges of volumetrically calculated OOIP (Figure 6). There is no cutoff of >1,000-bbl production. In comparison with Figure 5, the trend of Figure 6 shows the influence of low reported oil production.

In general, cumulative oil production makes a better prediction for larger oil fields, and smaller oil fields are more influenced by underreporting of oil production. For Illinois Basin fields, underreporting of oil production resulted in underpredicting CO_2 storage by 2 to 3 orders of magnitude.

Because MGSC divided oil fields according to miscibility type (miscible, immiscible, and near-miscible), oil fields in the study were divided according to miscibility type, too (Figure 7). ("Near-miscible" was for pressure and temperatures that were considered too close to be able to label an entire field as either miscible or immiscible and would have to be classified on a formation-by-formation basis within each field.) Miscibility classification was based primarily on depth, as well as anticipated pressure and temperature anticipated at these depths using a range of gradients.

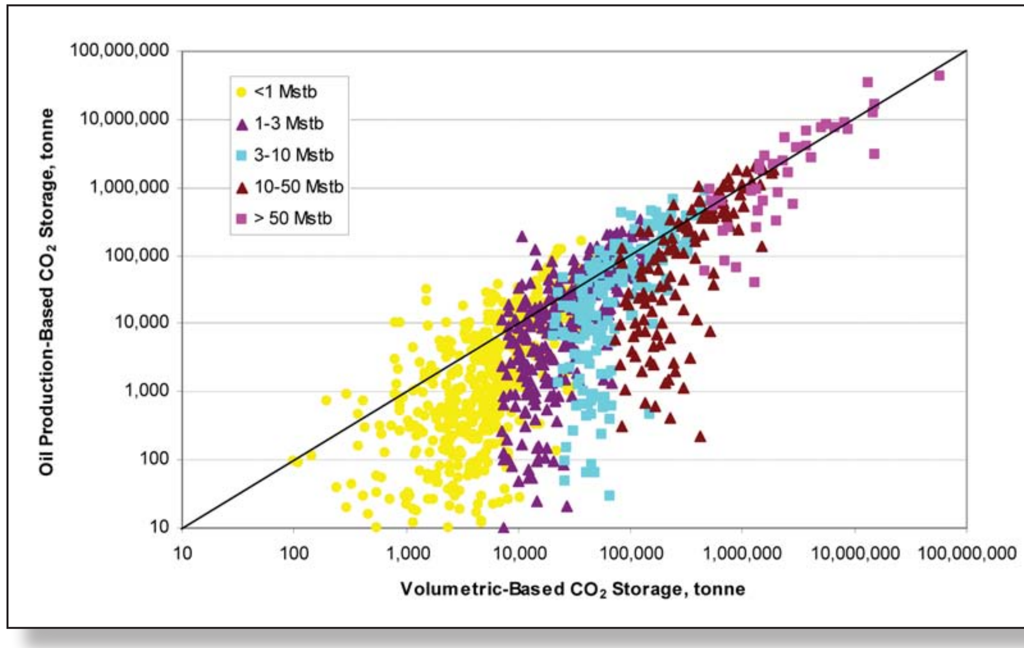

Figure 6. Oil fields in the basin are identified by three ranges of OOIP. Oil fields with larger volumetrically calculated OOIP (>50 Mstb) give results relatively similar to those between production- and volumetrics-based methods. For <50 Mstb, a large discrepancy is present, which is attributed to poorly reported oil production in the early history of the basin. (M is million)

Figure 7 suggests that cumulative oil production gives inferior results for immiscible CO_2 EOR formations. However, it is more likely an indication of production records. Immiscible fields are shallower than miscible and near-miscible classified oil fields. Generally in the Illinois Basin, shallow oil fields were discovered early in the Basin's history and have less-reliable production data. This plot further emphasizes the effect of poor production data on the CO_2 storage estimate with this method.

Summary

Using the cumulative oil production method in the Illinois Basin underpredicted CO_2 storage compared with the volumetric method, probably because of questionable pre-law production records. When exact production data (simulation dataset) were available, simulations suggest that the production-based method slightly overpredicts CO_2 storage, with increasing overprediction occurring at higher storage values.

In fields with good production data, the production-based method will give good results. In fields with underreported oil production, the CO_2 storage estimate may be to low by 2 to 3 orders of magnitude.

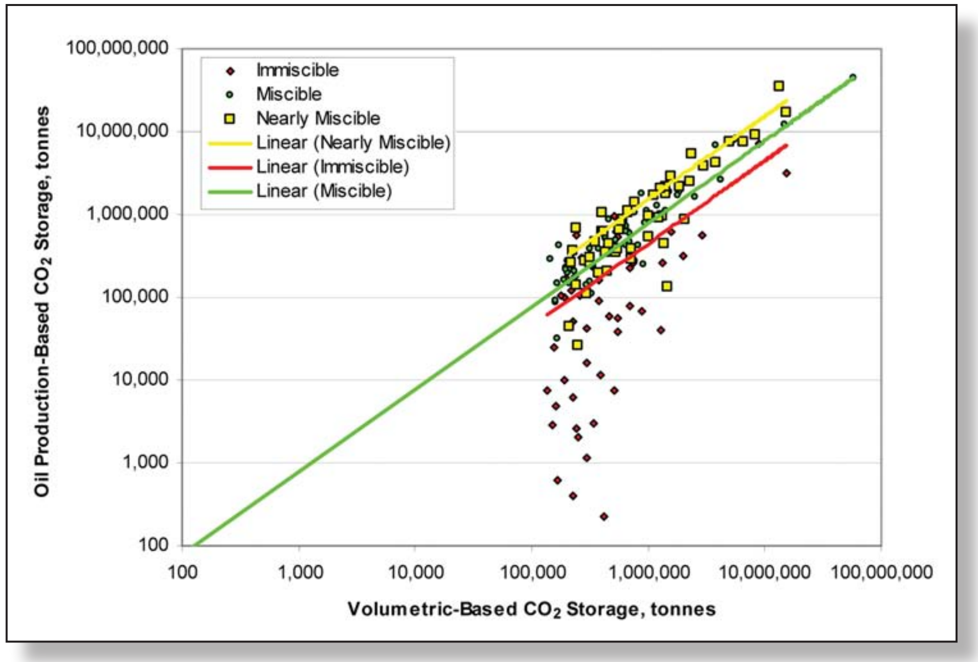

Figure 7. Oil fields in the basin are identified by miscibility classification, which is primarily governed by depth. Deeper oil fields with classifications of miscible and near-miscible show very similar storage estimates between the two methods.

Recommendation

The cumulative-oil-production-based method may slightly overpredict CO_2 storage capacity when good oil-production records are available and underestimate storage when poor production records are available. It is anticipated that the magnitude of the factor will have slight to modest effects on the storage estimate. In the Illinois Basin, lack of good production data accounted for a 15% underprediction of CO_2 storage using the production method.

On the basis of this study using the Illinois oil-field database, it is recommended that replacing cumulative oil production (primary and secondary) with an equivalent volume of CO_2 is an effective means of estimating CO_2 storage for oil formations, as compared with using compositional simulation-based storage factors with volumetrics. For National storage estimates that combines all storage sinks, in comparison with the storage in saline formations, any adjustment to the oil-field formation estimate would be of minimal consequence.

No change to the RCSPs' Phase I estimates of CO_2 storage in oil reservoirs is recommended.

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